Transmission Pricing Advisory Group

Draft note on ‘beneficiary pays’ and related HVDC issues

Version 1: For discussion with TPAG

9 March 2011

Note: This paper has been prepared for discussion with TPAG. Content should not be interpreted as representing the views or policy of the Electricity Authority or the Transmission Pricing Advisory Group.

Contents

1 Introduction and purpose

1.1.1 At the TPAG meeting of 24 February 2011, TPAG requested papers from the secretariat on:

(a) the link between "beneficiary-pays" and efficiency; and

(b) the differences between the HVDC link and other transmission assets that are relevant to transmission pricing.

1.1.2 As these two issues are related they are both covered in this paper. The two sections of this paper cover:

- The link between efficiency and "beneficiary pays". This includes:
  - a description of the beneficiary pays principle;
  - an outline of the costs and benefits that can be associated with a "beneficiary pays" approach; and
  - an outline of the relevant changes to the NZ transmission investment framework that might have an effect on the efficiency impacts of a beneficiary-pays principle; and
- Issues associated with applying a beneficiary-pays principle to the allocation of HVDC costs including whether there are differences between the HVDC link and other transmission assets that might be relevant to transmission pricing.

1.1.3 This paper does not seek to provide definitive views and has been prepared to prompt discussion amongst TPAG members.

1.1.4 Nor does this paper set out how "beneficiary pays" was applied with respect to the current TPM. This is covered in various Electricity Commission paper including the 'HVDC Transmission Pricing Methodology Explanatory Paper – Commission's Final Decision.'[1], Transmission pricing methodology – summary of submissions and provisional response paper - 11 April 2007, Transmission pricing methodology – Final decision paper - 7 June 2007.

2 The link between efficiency and 'beneficiary pays'

2.1 The beneficiary-pays principle

2.1.1 Beneficiary pays is a pricing approach based on the idea that the most efficient allocation of resources occurs when the beneficiary of a good or service pays the full cost of its provision. In conventional markets where there is little or no need for regulatory intervention this approach works well. Beneficiaries (consumers) will tend to pay for goods and services up to the point where they perceive that the benefit just exceeds the marginal cost.

2.1.2 Beneficiary pays is related to 'user-pays'. In some cases beneficiary pays is aligned with user pays, although in electricity networks there can be a differentiation. For example, a generator may benefit from a transmission asset (in terms of accessing higher electricity prices or accessing network reliability), but may not physically use the network for transmission or its power output.

[1] http://www.ea.govt.nz/document/5225/download/act-code-regs/ec-archive/rules-regs/rulebook-regs/guidelines/transmission-pricing/

2.2 The costs and benefits of beneficiary pays for transmission pricing

2.2.1 Using a "beneficiary pays" approach is often advocated as a means of encouraging efficient use of and investment in transmission networks. In transmission charging the beneficiary-pays approach can be applied either through commercially negotiated contracts, or through a regulated methodology which identifies beneficiaries. How it is applied is likely to be dependent on the prevailing regulatory framework and is likely to influence the expected costs and benefits.

2.2.2 Broadly, the benefits of a beneficiary-pays approach are efficiencies gained through incentives on participants. Participants who would be recognised as beneficiaries will have strong incentives to get involved in the investment decision-making processes, and strong incentives to ensure that a grid investment is the most cost-effective outcome, if they are required to pay for the investment. Under the existing regulatory regime, meaningful engagement in the transmission investment process can help ensure that when making decisions Transpower and the Commerce Commission have good quality information regarding the proposed investment and its alternatives,.

2.2.3 In contrast, if the costs of grid investments are spread across all (or many) participants, there will be incentives for the beneficiaries of an investment to lobby for more investment than may be required since they will only be required to pay a share of the total costs. Accordingly the behavioural incentives may not be well-aligned with the most efficient outcome. Under these circumstances, a central decision-maker must resist lobbying, and may be required to make investment decisions with poor or incomplete information, because the participants may not be incentivised to engage in the process or supply quality information.

2.2.4 The "beneficiary pays" approach works well where the beneficiaries are readily identified and can be readily involved in decision-making processes. Where the beneficiaries are difficult to identify, or where there are disputes about whether particular participants are beneficiaries, the costs of implementing a beneficiary pays approach may potentially outweigh the advantages.

2.2.5 On a transmission grid it is generally feasible to identify specific assets that are clearly related to particular grid users – these are generally assets required to connect grid users into the "core grid"[2]. In New Zealand the portion of charges known as "connection charges" have attempted to identify, and charge for, not only assets at the point of connection with the grid, but also assets that provide a connection link back to the "core grid" (so-called deep connection charges).

2.2.6 Connection charging has generally been successful in terms of identifying assets associated with different beneficiaries, and creating good behavioural incentives in decision-making processes. There has however been scope for inefficient lobbying and disputes over the boundary between the connection assets and the core grid. The boundary between the connection assets and the core grid provides scope for inefficient lobbying since assets on one side of the boundary will be paid for by the beneficiary, while assets on the other side of the boundary will be spread across many participants.

2.2.7 Identifying the beneficiaries of "core grid" investments can be difficult, has been controversial, is open to concerted lobbying, and is potentially subject to change.

2.2.8 There has been concerted lobbying, for example, about who is (and isn't) a beneficiary of the HVDC link. Thus there have been high ongoing transaction costs in identifying possible beneficiaries of core grid assets.

[2] In this note the term "core grid" is used to refer to that part of the grid where assets are used by a range of participants - load and generators. It does not refer to the definition of core grid as those parts of the grid serving more than 150MW of load.

2.2.9 The flow tracing approach outlined in the Stage 2 options paper is an approach that has the potential to better identify beneficiaries across the transmission grid, including parts of the core grid[3]. In this case, a beneficiary is identified with use and use is defined by share of flow. It may be feasible to implement flow tracing as a means of identifying beneficiaries, however there would be costs associated with implementation and debates about whether flow tracing appropriately identifies beneficiaries.

2.2.10 Even where beneficiaries can be identified, it is possible that the cost allocation can lead to short-run economic distortions if the allocation is based on usage. For example – a usage based allocation of costs to a group of participants may discourage full utilization of new transmission assets. The benefits of allocating costs to beneficiaries needs to exceed these short run economic distortions.

2.2.11 There are also potential dynamic efficiency impacts relating to a regulator's observance of the beneficiary pays principle. This is because following the principle, where possible, is good regulatory practice and failing to do so may be seen to be an arbitrary application of regulatory power. This may create regulatory and investment uncertainty.

2.2.12 For example, where a regulator is aware of beneficiaries, it should preserve an arrangement that beneficiaries pay as this replicates the outcome of a non-regulated process where beneficiaries are identified by the commitment to a contract. Likewise, if all parties could see that a regulator is aware of beneficiaries but does not seek to allocate costs to them, this may introduce a similar regulatory risk. If the regulator proclaimed, without sufficient evidence, some parties to be beneficiaries, then this also may lead to a dynamic efficiency cost.

2.2.13 This means that, even if there is no evidence of benefits from charging beneficiaries, for example from modelling the co-optimisation of generation and transmission, there could still be a net benefit from allocating costs to beneficiaries as that is good regulatory practice. If it is difficult to identify beneficiaries, or it remains controversial, then the dynamic efficiency of this aspect of good regulatory practice may be outweighed by the transaction costs of identifying the beneficiaries.

2.2.14 In conclusion, a beneficiary pays approach can provide efficiency benefits because if they are required to pay for the investment participants will have strong incentives to get involved in the decision-making process and strong incentives to ensure that a grid investment is the most cost-effective outcome. However, there can be costs associated with:

(a) identifying the beneficiaries, managing disputes and potential uncertainty arising from on-going disputes; and/or

(b) possible short-run economic distortions, depending on the allocation methodology.

2.3 Changes to the NZ transmission investment framework that might have an impact on the efficiency of a beneficiary-pays principle

2.3.1 As mentioned in paragraph 2.2.1, the beneficiary-pays approach can be applied either through commercially negotiated contracts, or through a regulated methodology which identifies beneficiaries.

2.3.2 Since 1996 the transmission investment environment has moved from a regime of beneficiary pays for new investment through the negotiation of commercial contracts, to one of a regulator ultimately determining whether investments are in the national benefit. Investment in the "core grid" and the

[3] Note that flow tracing was included in the Stage 2 options paper as a possible means of allocating costs to off-take customers in order to provide incentives for deferring transmission reliability investments.

allocation of investment costs are centrally determined. There is no longer a relationship between negotiated transmission contracts and transmission investment for investments in the “core grid”. This change has been driven by observations and experience that, for the core grid, there is a strong common good element to investment and the transaction costs to establish multi-lateral contracts are too high. The changes to the framework over the last 30 years are outlined in the attached Appendix A.

2.3.3 The changes suggest that the primary factor in determining that transmission investment in the “core grid” is efficient has become the regulated process overseen by the Commerce Commission.

2.3.4 However, as discussed earlier, participants who are paying for future grid assets, whether through a contractual framework or a regulated transmission pricing methodology, are more likely to take an interest in, and provide quality information to support, transmission investment decision-making by Transpower and the Commerce Commission. This is particularly the case were charges may not be able to be passed on by a participant and therefore impact directly on a its profit.

3 Issues associated with the application of the beneficiary-pays principles to the allocation of HVDC costs

3.1 History of HVDC Charges

3.1.1 The history of charging grid users for HVDC transmission is summarised in the following table:

Timeframe	Overview	HVDC Pricing Regime
Phase 1: **1988 to 1996** **Unbundling of Bulk Supply Tariff and TPM development**	Transmission pricing, as distinct from the pricing of delivered energy, was initiated in 1988 when ECNZ established Transpower as a separate, wholly owned subsidiary. The first real separation of the energy and transmission services provided by ECNZ was part of the so-called Nominated Quantity Option, which was offered to transmission customers in 1991.	• Initially no separate specific HVDC charge, although there was a SI Differential passed through to South Island off-take customers (first introduced in 1984 to recognise that the South Island consumers were closer to the main hydro schemes) • Later, an HVDC charge was put in place, recovering a 47% share of the cost of the HVDC link from Contact and ECNZ. The balance of 53% of the HVDC costs were recovered from off-take customers along with the other costs of transmission
Phase 2: **1996 to 1998** **Transition to, and impact of, the NZEM**	Key issues addressed in this period included: • Treating HVAC and HVDC assets separately because the economic life for the HVDC assets was considered to be significantly shorter than that of the HVAC assets • Allocating HVDC asset costs to “beneficiaries”, by changing the allocation of HVDC costs from 47% of the costs to all generators and 53% of the costs to off-take customers, to 100% to South Island generators	• Recover full cost of the HVDC link from South Island generators • Pay the HVDC losses and constraints rentals to South Island generators

Timeframe	Overview	HVDC Pricing Regime
Phase 3: **1999 to 2008** **Steady state**	Minor enhancements to TPM	• HVDC charges for South Island generators allocated according to peak injection MW • A proportion of overhead was allocated to generators through Connection and HVDC charges. Previously, overhead was recovered through Access charges
Phase 4: **2008 to present** **Regulation**	The introduction of the Electricity Governance Rules (EGRs) led to significant changes in how Transpower obtained approval for its TPM. The TPM applicable from 1 April 2008, which was approved by the Minister in 2007, was the culmination of the process set out in part F of the EGRs. Key HVDC issues addressed during this phase included the avoidability of HVDC charges, and the introduction of HAMI was designed to reduce this.	• HVDC revenue requirement allocated to South Island injection customers on the basis of historical anytime maximum injection (HAMI). • The allocation method uses the historical anytime maximum injection over the most recent and the four preceding capacity measurement periods.

3.1.2 This table highlights that how the costs of the HVDC transmission have been allocated has been a controversial ongoing issue. Note that, when the TPM was reviewed in 1996 through the application of a "beneficiary pays" approach, the framework for transmission pricing was based on an expectation that participants would contract for services.

3.2 Identifying the Beneficiaries of HVDC Transmission

Differences between the HVDC link and other transmission assets

3.2.1 If the HVDC transmission is to continue to be treated differently from other elements of the core grid, it will be important to expressly consider and record the rationale for doing so. For example, the HVDC transmission link could be distinguished on the basis that it is direct current rather than alternating current, it connects two integrated networks in separate islands, and it is possible to schedule flows across the HVDC link in a way that is not possible with transmission links in the AC network. It might also be distinguished in the future on the basis that it has been treated differently historically (see table above).

3.2.2 On the other hand, there is a rationale why no distinction is warranted. The System Operator when operating the power supply system and dispatching generation to meet demand deals with the HVDC link much as it does with the other constrained transmission links between regions. In other words, the System Operator schedules generation according to a merit order, and constrains generation on or off within regions, in order to accommodate constraints between regions. Rather than considering the transmission network as linking two regions, it considers it as 17 regions with constraints operating on the transmission links between those regions from time to time.

3.2.3 A principled approach that seeks to determine the beneficiaries of the transmission links between these 17 regions may be feasible, but is likely to be difficult. Presumably, the direction and timing of the electricity flows between the regions would need to be determined and some combination of generators and off-take customers within the regions on each side of the constraint would need to be identified as beneficiaries. This would need to take into account the variability of fuels supplies (hydro and wind in particular) and the probability of generation/transmission outages that could cause constraints across the transmission link.

3.2.4 Although application of this approach may be feasible, it is likely to be costly, controversial, and time-consuming. It may also be subject to change, since new generation and new transmission will tend to modify the expected electricity flows within the network and between regions.

Identification of HVDC beneficiaries

3.2.5 If the HVDC transmission is to continue to be treated separately, and it is deemed desirable to identify and charge the beneficiaries of the HVDC transmission, then a methodology for identifying beneficiaries will need to be agreed and made clear. Experience suggests that this will be controversial and subject to lobbying.

3.2.6 A methodology suggested in the past includes the idea that the beneficiaries are those participants that would voluntarily pay for the service if paying was the only means of receiving the service. In other words, if there was no opportunity to free-ride and benefit for a service that someone else was paying for. The extent of the benefit would be reflected in the amount they would pay for the service.

3.2.7 Applying this methodology is not straightforward since it raises counterfactual difficulties as follows:

- Is the appropriate counterfactual to consider all generation, transmission and demand to be in place except for the HVDC transmission, and then to consider who would pay to have the service reinstated and how much they would pay?

or

- is the counterfactual to consider the situation in which none of the investments have been made (either HVDC or generation) and to consider, ex-ante, who would be prepared to invest in the combination of generation and HVDC transmission and how much they would pay?

3.2.8 Conceptually the second approach seems to be more appropriate in the situation where new capital intensive assets with economies of scale are involved. For example, ex-ante a SI hydro generator may be prepared to pay up to the difference between the cost of new generation in the North Island and the South Island to pay for the HVDC link. However once the SI generator has made the decision to invest it would be prepared to pay considerably more to retain the link. The former approach may be more appropriate when additional capital is required to maintain the capacity of a link, but even then the appropriate test should reflect the willingness to pay to restore the capacity. Neither alternative appears straightforward and is liable to lead to concerted lobbying.

4 Summary

4.1.1 This note suggests the following observations for TPAG consideration:

- A beneficiary pays approach can provide efficiency benefits because participants will have strong incentives to get involved in the decision-making process and strong incentives to ensure that a grid investment is the most cost-effective outcome, if they are required to pay for the investment. However, there can be costs associated with:

  - identifying the beneficiaries, managing disputes and potential uncertainty arising from on-going disputes.
  - possible short-run economic distortions, depending on the allocation methodology.

- The transmission investment framework is different from the framework that applied when TPM was first introduced and this may have some affect on the efficiency impacts of a beneficiary-pays approach.
- Identifying beneficiaries of core grid investments is complex, likely to be controversial and likely to be subject to change.
- There are differences between the HVDC link and other transmission assets but, considered alone, these may not justify treating the HVDC link separately.
- Identifying the beneficiaries of HVDC transmission is complex and controversial and risks ongoing transaction costs from future lobbying.

Appendix A

Timeframe	Transmission Investment
Pre 1987 **Centralised government process**	Transmission investment was undertaken in conjunction with demand forecasting and generation investment through a centralised process operated by a government department.
1988 to 1996 **Corporate model**	Transmission investment was undertaken in conjunction with demand forecasting and generation investment through a centralised process operated by a subsidiary of ECNZ – a state-owned integrated electricity generating and transmission business.
1996 to 2003 **Market-based arrangements**	Transmission investment was undertaken by Transpower – an independent state-owned transmission business. The process was no-longer centralised and coordinated with generation investment and there was an expectation that grid users would contract, on a disaggregated basis, with Transpower for the services that they required. Grid investments needed to be underpinned by these contractual arrangements. Closing off contractual negotiations proved very difficult and transmission investment, particularly on the "core grid", largely stalled.
2003 to 2010 **Electricity Commission**	Transmission investment was undertaken by Transpower – an independent state-owned transmission business. The EGRs regulated the transmission investment process and over time the investment approval process, the Grid Reliability Standards (GRS), and the Grid Investment Test (GIT) were developed and incorporated in the Rules The Electricity Commission was responsible for ensuring that transmission investment was efficient.
2011 **Commerce Commission**	Transmission investment is undertaken by Transpower – an independent state-owned transmission business. The investment approval process is now overseen by the Commerce Commission. The GIT (to be replaced by an Input Methodology) remains central to the process.